

# Numerical study on Effects of Different Coal on Combustion Characteristics in Coal-fired Boiler

VARDIREDDY VISWESWARA REDDY, DADAMIYAH ARSHAD BASHA, K PAVAN KUMAR REDDY

ASSOCIATE PROFESSOR<sup>1</sup> ASSISTANT PROFESSOR<sup>2</sup> ASSOCIATE PROFESSOR<sup>13</sup>

[yvindustries@gmail.com](mailto:yvindustries@gmail.com), [arshad9175@gmail.com](mailto:arshad9175@gmail.com), [pavan.intell@gmail.com](mailto:pavan.intell@gmail.com)

Department of Mechanical Engineering, Sri Venkateswara Institute of Technology,

N.H 44, Hampapuram, Rappthadu, Anantapuramu, Andhra Pradesh 515722

## ABSTRACT

The efficiency of coal-fired power plants is directly proportional to the quality of the coal used. The poor combustion properties of low-quality coal contribute to environmental issues including ash accumulation. The flow and combustion processes in a full-scale furnace were studied using computational fluid dynamics (CFD) in this work. Three different sub-bituminous coals, designated as A, B, and C, were tested. By monitoring the furnace's flow, temperature, and species concentration, we can predict the coals' burning performance. After receiving the exact boiler furnace geometry from the operator, it was transformed into a computational fluid dynamics (CFD) model with just minor alterations made for mesh optimisation. According to the study, the highest combustion temperature was observed for coal B, which was around 1400°C. Ironically, coal C is predicted to generate the highest velocity peak in specific furnace regions while having the shortest flame duration, necessitating more flow to achieve the same penetration as other coals. The trace of the oxygen concentration inside the furnace demonstrates optimal combustion, with little oxygen left in the rear pass supplied by Coal A.

## Introduction

Reliable, affordable and clean energy supply is one of the basic needs of humankind. Today, our energy supply system is undergoing a long-term transition from its conventional form to a more sustainable and low carbon style, especially addressing greenhouse gas (water, carbon dioxide, methane, nitrous oxide, chlorofluorocarbons and aerosols) emissions into the atmosphere. Strong evidence suggests that both the average global temperature and the atmospheric CO<sub>2</sub> concentration have significantly increased since the onset of the industrial evolution, and they are well correlated. Concerns over climate change have led to mounting efforts on developing technologies to reduce carbon dioxide emissions from human activities. Technological solutions to this problem ought to include a substantial improvement in energy conversion and utilization efficiencies, carbon capture and sequestration (CCS), and expanding the use of nuclear energy and renewable sources such as biomass, hydro-, solar, wind and geothermal energy. Coal has been and will continue to be one of the major energy resources in the long term because of its abundant reserves and competitively low prices, especially for the use of base-load power generation. For instance, the share of coal in world energy consumption was 29.4% in 2009, as opposed to 34.8% for oil and 23.8% for natural

gas. In terms of power generation, coal continues to be the dominant fuel, contributing about 45% of the total electricity in the US in 2009, and about 80% in China. Several technologies have been proposed for reducing CO<sub>2</sub> emission from coal-fired power generation, namely post-combustion capture, pre-combustion capture and oxy-fuel combustion capture:

- Pre-combustion capture: Fuel is either gasified or reformed to syngas, a mixture of carbon monoxide and hydrogen, which is then shifted via steam reforming. CO<sub>2</sub> is then separated from the syngas by shifting carbon monoxide with steam, yielding pure hydrogen (water gas shift reaction). The Integrated Gasification Combined Cycles (IGCC) for coal is an example of pre-combustion capture system.
- Post-combustion capture: CO<sub>2</sub> is separated from the flue gases using chemical solvents, sorbents (such as calcium oxide or carbon fibres) and membranes without changing the combustion process. However, the addition of a post-combustion capture unit may change the steam cycle because large quantity of low pressure steam must be extracted from the steam cycle for the solvent regeneration process.
- Oxy-fuel combustion: Instead of using air as oxidizer, pure oxygen (O<sub>2</sub>) or a mixture of O<sub>2</sub> and recycled flue gas is used to generate high CO<sub>2</sub> concentration product gas; therefore, the combustion process is significantly changed. Chemical-Looping Combustion (CLC) is another combustion process that belongs to the oxy-fuel combustion category, in which pure oxygen rather than air is supplied by metal oxides for combustion, such that the mixing between CO<sub>2</sub> and N<sub>2</sub> is inherently avoided.

This technology is not the primary focus of this paper, and, the reader is referred to for more details on CLC.

In general, the technologies described above can be applied to generate energy from natural gas and coal with the exemption of some low rank coals due to unresolved engineering challenges, however, because of the important role of pulverized coal in base load electricity generation and its contribution to CO<sub>2</sub> emission, this study is primarily concerned with the combustion of pulverized coal, although some mention is made of other fuels as well.

**Table 1-1. Representative performance and economics data for the three main capture technologies,**

Performance	Supercritical PC <sup>a</sup>		SC <sup>b</sup> PC-Oxyfuel	IGCC <sup>c</sup>	
	w/o capture	w/ capture	w/ capture	w/o capture	w/ capture
Generating efficiency	38.5%	29.3%	30.6%	38.4%	31.2%
Efficiency penalty	CO <sub>2</sub> recovery (heat): -5%		Boiler/FGD: 3%	Water/Gas shift: -4.2%	
	CO <sub>2</sub> compression: -3.5%		ASU: -6.4%	CO <sub>2</sub> compression: -2.1%	
	CO <sub>2</sub> recovery (power): -0.7%		CO <sub>2</sub> compression: -3.5%	CO <sub>2</sub> recovery: -0.9%	
			Other: -1%		
Capital Cost (\$/kWe) <sup>e</sup>	1330	2140 (1314) <sup>d</sup>	1900 (867) <sup>d</sup>	1430	1890
COE (c/kWh) <sup>e</sup>	4.78	7.69	6.98	5.13	6.52
Cost of CO <sub>2</sub> (\$/t) <sup>e</sup>	40.4		30.3	24.0	

PC: pulverized coal; b SC: supercritical; c IGCC: Integrated gasification combined cycle; d Figures in parenthesis are the expected capital cost for retrofits; e Based on design studies done between 2000 & 2004, a period of cost stability, updated to 2005\$ using CPI inflation rate. These three major carbon capture technologies for coal-fired power plants have been studied in terms of power generation efficiency, capital costs and costs of electricity (COE). Representative energy efficiency and economic performance of these technology options are compared in Table 1-1. All of these estimates are based on 90% CO<sub>2</sub> capture in rebuilt and retrofitted scenarios. The cost of CO<sub>2</sub> indicates the cost that is incurred to capture 1 metric ton carbon dioxide without transportation and storage. Although the absolute numbers vary by few percentage points in these studies, all reports show the same trends. In general, all three capture technologies result in an efficiency penalty, while oxy-fuel capture and pre-capture or IGCC show advantages over post-combustion capture in terms of COE and cost of CO<sub>2</sub>. The IGCC technology yields a higher generation efficiency and a slightly lower cost than oxy-fuel combustion technology. However, all these technologies are in their early stages of development and still have great potential for improvement. In particular, these studies have a common conclusion that oxy-fuel combustion is the most competitive technology option for retrofitting existing coal-fired power plants, which at the moment have the largest potential for CCS. Although the number of newly-built coal power generation units declined since 1990s', there is a resurgence of new coal power plants in recent years. Moreover, about 98.7 GW or 29% of all the existing coal-fired power capacity were built after 1980. This situation is even more prominent in developing countries such as China and India, where the coal power generation capacity has been booming in the last two decades. It can safely be assumed that a sizable reduction of CO<sub>2</sub> emission from existing plants would come from retrofits. Oxy-fuel combustion systems have a natural

advantage in retrofitting existing PC power plants because they can reuse most of the existing plant equipment. The advantages of oxy-fuel combustion as a retrofit technology are also indicated in Table 1-1. The capital cost for supercritical PC retrofits with oxy-fuel is \$867/kWe, which is significantly lower than the capital cost of post-combustion retrofit (\$1314/kWe) and of newly-built IGCC plants (\$1890/kWe). Considering the advantages of a relatively moderate efficiency penalty and the lowest retrofit capital expenditure, atmospheric oxy-fuel combustion systems have been widely accepted as a competitive carbon capture technology. More recently, it has been adopted to substitute the original IGCC plan in the U.S. DOE FutureGen 2.0 program. Previous studies have reviewed its fundamentals and characteristics, as well as recent developments in pilot-scale and commercial-scale demonstration plants. While successful, the technology still faces many challenges, such as air leakage into the flue gas system, the relatively low energy efficiency, the need for efficient air separation and better plant integration and flue gas clean-up, among others. In particular, significant challenges are expected in the combustion process itself, including stability and emissions, burner design and scaling, as well as determining of optimal operating conditions. Oxy-Fuel Combustion for CCS Development of the Oxy-Fuel Technology for CCS The idea of applying oxy-fuel processes with flue gas recycle in coal-fired plants to control the CO<sub>2</sub> emission and/or produce high concentration CO<sub>2</sub> for enhanced oil recovery (EOR) was first proposed in 1982. Following these proposals, Argonne National Laboratory (ANL) pioneered the investigation of this process in the mid and late 1980s, focusing on the system and its combustion characteristics. Soon after, more and more researchers agreed that this system complements the two other major approaches for carbon

dioxide capture, which led to a renewed interest in this technology in the 1990s. Research conducted by the International Flame Research Foundation (IFRF), CANMET

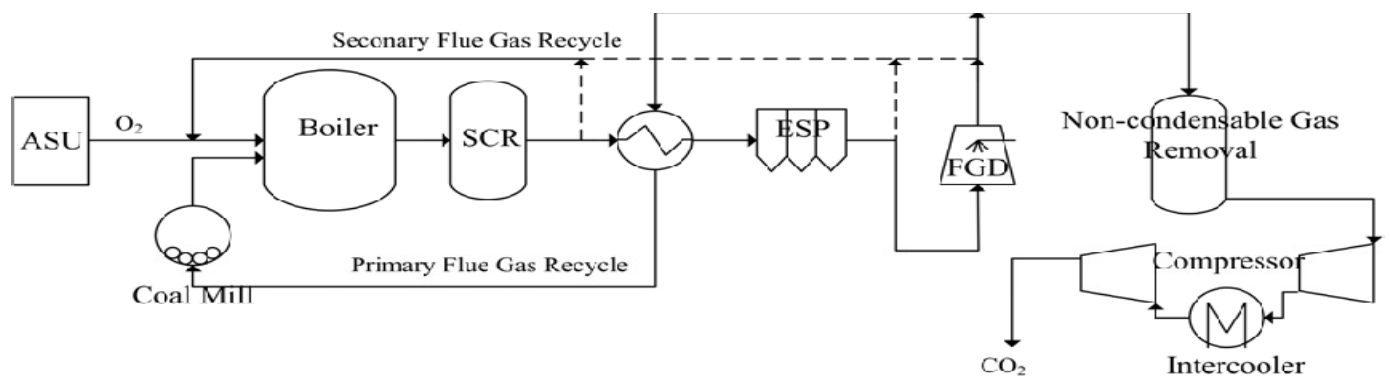
, IHI, as well as other institutes and industrial parties has made considerable contributions in understanding of this process.

Along with the research and development on their-like oxy-coal technology, pilot and large scale demonstration plants are being built around the world. Wall et al. surveyed research on oxy-fuel technology, from pilot-scale tests, to industry-scale tests and full-scale demonstrations, and compiled the historical development of this technology worldwide. The year 2008 marks an important milestone with the commissioning of the world's first 30 MW demonstration plant in Germany. More large-scale demonstrations in industry-scale coal-fired boilers have been planned or are already underway, as shown in Table 1-2 based on the work of Wall et al. and Herzog. Success in these demonstrations is expected to lead to wider commercial deployment. Recent research has also focused on extending the range of operating conditions of oxy-coal combustion to improve energy efficiency, environmental performance and economic soft

histechnology. For instance, pressurized systems have been proposed for both oxy-coal combustion with recycled flue gases and oxy-syngas combustion in combination with solid fuel gasification technology. These approaches are described in greater detail in the following sections.

#### Atmospheric Oxy-Coal Combustion Systems with Flue Gas Recycle

The atmospheric oxy-coal combustion system shown in Figure 1-1 was first introduced as a short-term solution to retrofit existing coal-fired power plants to include the option of CCS. In most oxy-coal system studies, recycled flue gases at various recycle ratios are used to control the flame temperature in the combustor and as a result, the flue gas consists primarily of steam which is later removed through condensation, and carbon dioxide which is purified before being sent for compression and sequestration. The additional equipment required, when compared with air-fired systems, is described below:



**Figure 1-1. Atmospheric oxy-coal combustion system with flue gas recycle proposed for carbon capture in coal power plants.**

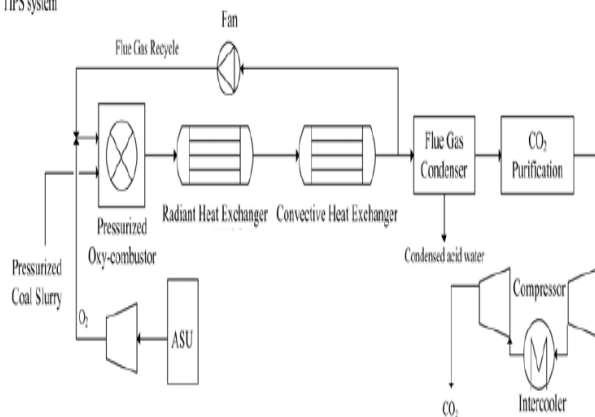
**Air Separation Unit (ASU):** When retrofitting existing PC power plants, the system primarily uses existing equipment with the exception of an ASU used to produce an oxygen-rich stream for combustion. Currently, the only ASU technology that can meet the volume and purity demand of a large scale coal-fired utility boiler is based on cryogenic distillation.

Air is compressed, cooled and cleaned prior to being introduced into the distillation column to separate air into an oxygen-rich stream and a nitrogen-rich stream. Cryogenic air separation is energy intensive, consuming about 0.24 kWh/kg O<sub>2</sub> with 95% oxygen purity. Although the oxygen purity requirement for oxy-coal combustion (85~98%) is lower than that needed in the process industry (99.5~99.6%) [39], these cryogenic separation processes can consume more than 15% of the gross power output.

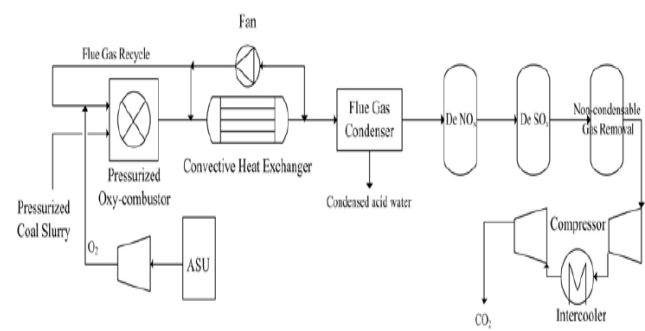
**Carbon Dioxide Purification Unit (CPU):** CPU consists of gas clean-up units to remove water, particulate matter and other pollutant gases from the flue gas before being compressed for sequestration. Because oxy-combustion is compatible with retrofits, selective catalytic reduction (SCR), electrostatic precipitator (ESP) and flue gas desulfurization (FGD) are typically retained as means of NO<sub>x</sub>, particulate matter and SO<sub>x</sub> removal from the flue gases. This method is also suitable for use in conjunction with amine-type absorbents for post-combustion capture plants.

It has been widely accepted that the non-condensable impurities, such as O<sub>2</sub>, may cause corrosion in the pipeline during transportation, and this has raised doubts about the safety of the storage sites. Therefore, after the removal of acid gases such as SO<sub>x</sub> and NO<sub>x</sub>, non-condensable N<sub>2</sub>, O<sub>2</sub>, and Ar should also be purged using a non-condensable gas purification unit. This unit is made of multi-stage compression units with inter-stage cooling in order to separate out the inert gases. Up to the time of this review, there are still no agreed upon standards re-

(a) TIPS system



(b) ENEL system, further analyzed by MIT



Pressurized oxy-coal combustion systems proposed for carbon capture in coal power plants,

a) Schematic of the Thermo Energy Integrated Power System (TIPS), (b) System proposed by ENEL based on a combustion process patented by ITEA,

**Pressurized Oxy-Coal Combustion Systems** Pressurized oxy-fuel combustion systems have been proposed recently, with the objective of improving the energy efficiency by recovering the latent heat of steam in the flue gas. The flue gas volume is reduced under elevated pressure, which results in smaller components and possible reductions in capital cost for the same power output. Several studies have reported on the technical and economic feasibility of this process, all concluding that

regarding the required purity of CO<sub>2</sub> for storage and sequestration. However, it should be noted that the acceptable degree of purity of the storage-ready CO<sub>2</sub> results from a trade-off between efficiency losses and operational costs during purification and the safety demands of transportation and storage.

**Flue Gas Recycle (FGR) System:** Recycled flue gas is required to moderate the combustion temperature. Considering system efficiency and operation practices, flue gases can be recycled at different locations downstream of the economizer in the form of wet or dry cycles. In the early stages of oxy-coal system studies, the requirement on CO<sub>2</sub> purity was not stringent and the desulfurization and de-NO<sub>x</sub> equipment were regarded as unnecessary. Therefore, all the flue gas was proposed to be extracted from a single location downstream of the ESP in wet or dry forms. Later on, Dillon et al. proposed flue gas recycling at different locations for the primary (used for transporting coal) and secondary streams for the sake of energy efficiency: while the primary recycle has to be dried and reheated to 250-300 °C to take up moisture from the coal feed, the secondary stream can be recycled at high temperatures without drying to eliminate thermodynamic losses caused by cooling and re-heating.

Today, with a stricter requirement on CO<sub>2</sub> purity for pipeline transportation and storage, pollution control equipment have been again taken into account in the flue gas recycle configurations. Moreover, since SO<sub>2</sub> concentration in the flue gas may accumulate due to flue gas recycle, resulting in 2 or 3 times higher concentration than in conventional air-firing systems, the primary recycle has to be at least partially desulfurized for medium and high sulphur coal, to avoid corrosion in the coal mill and flue gas pipes.

he overall process efficiency improves with increasing operating pressure. This is mainly because latent heat recovery from the flue gases becomes possible at higher temperatures.

Other potential advantages of pressurized oxy-fuel systems are the reduction of the auxiliary power consumption such as the recycle fan work, and the elimination of air ingress into the system. However, there are challenges associated with combustion and heat

transfer characteristics at elevated pressures, and hence the burners, steam/gas FURNACES and condensing FURNACES must be redesigned.

Figure 1 illustrates two different pressurized oxy-coal combustion systems proposed in the literature. One of the first designs is the Thermo Energy Integrated Power System (TIPS) proposed and studied by CANMET and Babcockpower. This system (Figure 1-2a) uses a pressurized combustion unit and FURNACES, as well as a flue gas condenser (FGC). Downstream of the radiated boiler and convective FURNACES, steam in the flue gases is condensed in the FGC, where most of the latent heat in the flue gas is recovered by the feed water in the steam cycle. The rest of the flue gas, which is essentially CO<sub>2</sub>, is purified and compressed to the sequestration specifications. In contrast, the hot flue gases from the pressurized combustor is quenched to about 800 °C by the recycled cold flue gas, eliminating the need for a radiant FURNACE and thus incurring a lower capital cost. It should be noted that in these

pressurized oxy-coal systems coal is fed in the form of coal-water slurry (CWS). Since the pressurized system takes advantage of the latent heat recovery from the steam in the flue gas,

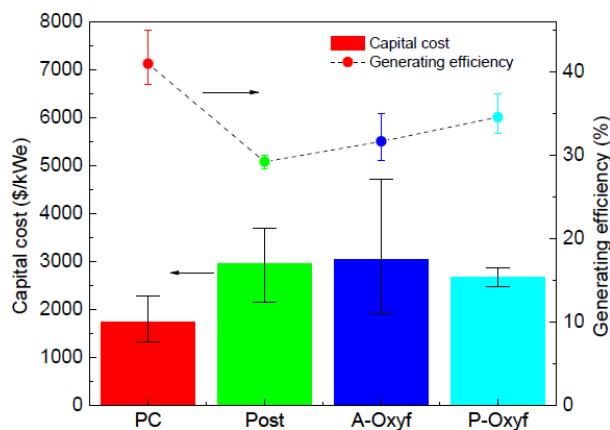
using a coal-water slurry does not significantly decrease the overall energy efficiency.

For the pressurized oxy-fuel power plants with CO<sub>2</sub> enriched flue gas streams, desulfurization and NO<sub>x</sub> removal solutions have been proposed with

potentially lower cost and higher energy efficiency, using a single chamber chemistry and nitric acid chemistry at elevated pressures. For instance, Air Products utilizing two

high pressure countercurrent reactive absorption columns (see Figure 1-2 (b)) combines them into a single high pressure column to remove SO<sub>x</sub> as H<sub>2</sub>SO<sub>4</sub> and NO<sub>x</sub>

as HNO<sub>3</sub>. Both solutions claim to have significantly reduced the cost of CO<sub>2</sub> purification with the latter having an advantage in terms of reduced power consumption and capital cost.



## Energy Efficiency Performance of the Oxy-Coal Combustion Systems

An important question to address at this juncture is the comparative performance of the atmospheric and pressurized oxy-fuel combustion systems described above. Figure 1-3 shows the capital expenditure (\$/kWe) and efficiency (HHV%) of these systems for newly-built power plants, compared to the performance of supercritical pulverized coal systems without capture and with post-combustion capture..

For instance, fuel type, size and configuration of the power plants, percentage of CO<sub>2</sub> captured, and parameters of the steam turbine, etc. Allowing for differences in modelling assumptions, the results from these studies are averaged in Figure 1-3, with the minimum and maximum values shown as error bars; and they should only be compared qualitatively.

System efficiency estimates showed a loss of about 10-15% percentage points when post-combustion capture is added to the base case PC power plant. On the other hand, the atmospheric oxy-fuel combustion shows an advantage of 1-5 percentage points when compared with post-combustion capture; while the pressurized system gains a further 3 percentage points efficiency. The main advantage of pressurized oxy-fuel system is the higher saturation temperature of water at elevated pressures, which enables more thermal energy recovery and the recuperation of latent enthalpy, as stated previously. Although the power consumption of the ASU is higher in the pressurized combustion system, the power savings in the CO<sub>2</sub> compression unit and in the recycled flue gas compressor are even higher, culminating in a better overall efficiency.

## CFD Modeling of Pulverized Coal Combustion and the Challenges under Oxy-Fuel Conditions

### Overview

CFD techniques have become the third dimension in fluid dynamics and combustion studies alongside analytical modeling and experimental diagnostics. CFD provides a relatively inexpensive (when sub models are used in connection with Reynolds-averaged Navier-Stokes (RANS) or when using coarse grain large-eddy simulation (LES) models) and indispensable tool to perform comprehensive studies on the fluid flow, heat transfer and chemical reactions in combustion. Currently, CFD modeling of oxy-coal combustion utilizes approaches and sub-models that are similar to those developed under air-fired conditions. With the accumulated knowledge on the fundamental differences between air-fuel and oxy-fuel combustion, some effort has gone into developing and validating sub-models for the new combustion environment. A selection of the CFD simulation studies on oxy-fuel combustion is summarized in Table 2-1, which includes the sub-models used for turbulence, radiation heat transfer, char combustion and homogeneous reactions. Since the existing sub-models were developed for conventional air-coal combustion, their assumptions and approximations may not be valid in the CO<sub>2</sub>-rich environment. In the following sections, the development of CFD sub-model for an accurate prediction in oxy-coal combustion is reviewed, and the findings of these recent numerical studies are summarized.

**Table 2-1. Summary of CFD simulations and their sub-models for oxy-fuel combustion.**

Author	Simulated object Facility	Fuel	Modeling approaches			Char Combustion	Homogeneous Reaction Mechanism	Chemistry- Turbulence
			Code	Turbulence	Radiation			
Wang et al. [28]	BCL Subscale combustor	Wage coal	1-DICOG (1-D)	N/A	Zone Method [128], transparent gas	C+O <sub>2</sub> C+CO <sub>2</sub> C+H <sub>2</sub> O	Volatiles combustion	Chemical Equilibrium
Khare et al. [129]	IHI 1.2 MWth vertical pilot scale test facility	Coal A	Fluent	$k-\epsilon$	P-1 WSGG	C+O <sub>2</sub>	Volatiles combustion	Chemical Equilibrium
Nozaki et al. [77]	IHI 1.2 MWth horizontal combustion test facility	Coal A/B	VEGA-3	$k-\epsilon$	Multi-flux Radiation model [130] Three-gray-gas model [131]	C+O <sub>2</sub> C+CO <sub>2</sub> C+H <sub>2</sub> O	Volatiles combustion	EBU
Chui et al. [132]	CANMET 0.3 MWth VCRF	Western Canadian sub-bituminous coal	CFX-TASCflow	Standard $k-\epsilon$	N/A	C+O <sub>2</sub>	Volatiles combustion	EBU
Rehfeldt et al. [78]	E.ON 1 MWth horizontal firing facility and IVD 500 kWth down firing facility	Tselentis coal and Lausitz lignite coal	Fluent	Standard $k-\epsilon$	DO	C+O <sub>2</sub> C+CO <sub>2</sub>	N/A	N/A
Toporov et al. [133]	RWTH Aachen U test facility	Rhenish lignite	Fluent	$k-\epsilon$	DO WSGG	C+O <sub>2</sub> C+CO <sub>2</sub> C+H <sub>2</sub> O	Volatile breakup CO and H <sub>2</sub> burning [134]	Finite Rate/Eddy Dissipation
Chen et al. [62]	ISOTHERM PWR® 5 MWth pressurized test facility	Bituminous coal	Fluent	Realizable $k-\epsilon$ $k-\omega$	DO WSGG	C+O <sub>2</sub> C+CO <sub>2</sub> C+H <sub>2</sub> O	Modified JL	Finite Rate/Eddy Dissipation
Andersen et al. [135]	100 kW down-fired furnace [68]	Propane	Fluent	Realizable $k-\epsilon$	P-1	N/A	WD [136] and Modified WD [135], JL [137] and Modified JL [135]	EDC
Vascellari et al. [138]	IFRF 2.4 MW furnace	Gottelborn hvBp coal	Fluent	Standard $k-\epsilon$	P-1	C+O <sub>2</sub> C+CO <sub>2</sub> C+H <sub>2</sub> O	Volatile decomposition, tar partially oxidation, Modified JL [139]	EDC
Muller et al. [140]	IFK 0.5 MWth test facility	Lausitz lignite	AIOLOS	Standard $k-\epsilon$	DO	C+O <sub>2</sub>	JL [137]	EDC
Nikolopoulos et al. [142]	330 MWe PC boiler in Meliti power plant, Greece	Lignite from Achlada mine	Fluent	Standard $k-\epsilon$	Leckner's model [141] DO EWBM	C+CO <sub>2</sub> C+H <sub>2</sub> O	Volatile combustion and CO burning	Finite Rate/Eddy Dissipation
Edge et al. [143]	0.5 MWth Air- and oxy-fired combustion test facility with Doosan Babcock triple-staged low-NOx burner and IFRF Aerodynamically air-staged burner	Coal A and B	Fluent	RNG $k-\epsilon$ and LES	DO WSGG/FSK	NA	Volatile combustion and CO burning	EDM

Eaton et al. (1999) present a revision of combustion models. The models are generally based on the fundamental conservation equations of mass, energy, chemical species and momentum, while the closure problem is solved by turbulence models such as the  $k-\epsilon$  (Launder and Sharma, 1974), combustion models like Arrhenius (Kuo, 1996; Turns, 2000), Magnussen – EBU – “Eddy Breakup” (Magnussen and Hjertager, 1976); radiative transfer models based on the Radiative Transfer Equation – RTE (Carvalho et al., 1991) and models to devolatilization and combustion of solid and liquid fuels.

Abbas et al. (1993) describe an experimental and predicted assessment of the influence of coal particle size on the formation of NO<sub>x</sub> of a swirl-stabilized burner in a large-scale laboratory furnace. Three particle size distributions, 25, 46, and 121  $\mu\text{m}$  average size, of high volatile coal were fired under similar operation conditions. The data presented combined detailed in-flame measurements of gas temperature, gas species concentrations of CO,

CH<sub>4</sub>, O<sub>2</sub>, NO<sub>x</sub>, HCL, NH<sub>3</sub>, particle burnout, and “on-line” N<sub>2</sub>O, with the complementary predicted studies. The predicted results are in good agreement with experimental data. Although the NO<sub>x</sub> emission trends with particle size are similar, predicted values for each fraction are higher, suggesting a limitation in the NO<sub>x</sub> reducing mechanisms used in the model. Three mechanisms – thermal, fuel and prompt – were used to calculate the NO<sub>x</sub> formation.

Xu et al. (2000) employed the CFD code to analyze a coal combustion process in a front wall pulverized coal fired utility boiler of 350 MW with 24 swirl burners installed at the furnace front wall. Five different cases with 100, 95, 85, 70 and 50% boiler full load were simulated. Comparisons were addressed, with good agreement between predicted and measured results in the boiler for all but one case thus validating the models and the algorithm employed in the computation.

Liet al. (2003) numerically investigated the combustion process using only a two-fluid model (instead of the Eulerian gas – Lagrangian particle models) for simulating three-dimensional turbulent reactive flows and coal combustion. To improve the simulation of the flow field and NO<sub>x</sub> formation, a modified  $k-\epsilon - k_p$  two-phase turbulence model and a second-order moment

(SOM) reactive rate model were proposed. The proposed models were used to simulate NO<sub>x</sub> formation of methane-air combustion, and the prediction results were compared with those using only the presumed-PDF (Probability Density Function)-finite reaction-rate model and experimental data. The proposed models were also used to predict the coal combustion and NO<sub>x</sub> formation at the exit of a double air register swirl pulverized-coal burner. The results indicate that a pulverized coal concentrator installed in the primary air tube of the burner has a strong effect on the coal combustion and NO<sub>x</sub> formation.

In a numerical investigation, Kurose et al. (2004) employed a three-dimensional simulation to the pulverized coal combustion field in a furnace equipped with a low-NO<sub>x</sub> burner, called CI- $\alpha$ , to investigate in details the combustion processes. The validities of available NO<sub>x</sub> formation and reduction models were investigated too. The results show that a recirculation flow is formed in high-gas temperature region near the CI- $\alpha$  burner outlet, and this lengthens the residence time of coal particles in this high-gas-temperature region, promotes the evolution of volatile matter and the process of char reaction, and produces an extremely low-O<sub>2</sub> region for effective NO reduction.

Zhan et al. (2005) presented a numerical investigation on the coal combustion process using an algebraic unified second-order moment (AUSM) turbulence-chemistry model to calculate the effect of particle temperature fluctuation on char combustion. The AUSM model was used to simulate gas-particle flows in coal combustion including sub-models as the  $k-\epsilon - k_p$  two-phase turbulence model, the EBU-Arrhenius volatile and CO combustion model, and the six-flux radiation model. This simulation results indicate that the AUSM char combustion model presented good results, since the latter totally eliminates the influence of particle temperature fluctuation on char combustion rate.

Bosoga et al. (2006) presented a study developing a CFD model for the combustion of flow-grade lignite and to characterize the combustion process in the test furnace, including the influence of the geometry of burner and furnace. A number of computations were made in order to predict the effect of coal particle size, the moisture content of lignite, and the influence of combustion temperature and operation of the support methane flame on the furnace performance and emissions. The influence of lignite predrying was also modeled to investigate the effects of reduced fuel consumption and CO<sub>2</sub> emissions. It was found that the increase of moisture tends to reduce NO<sub>x</sub>, and the methane support flame greatly increases NO<sub>x</sub>.

In another work, Backreedy et al. (2006) presented

anumerical and experimental investigation of the coal combustion process to predict the combustion process of pulverized coal in a 1 MW test furnace. The furnace contains a triple-staged low-NOx swirl burner. A number of simulations were made using several coal types in order to calculate NOx and the unburned carbon-in-ash, the latter being a sensitive test for the accuracy of the char combustion model. The NOx modeling incorporates fuel-NO, thermal, and prompt mechanisms to predict the NO formation on the combustion processes.

Kumar and Sahur (2007) studied the effect of the tilt angle of the burners in a tangentially fired 210 MW boiler, using commercial code FLUENT. They showed the influence of the tilt angle in the residence time of the coal particles and consequently in the temperature profiles along the boiler.

Asotani et al. (2008), also using the code FLUENT, studied the ignition behavior of pulverized coal clouds in a 40 MW commercial tangentially fired boiler. The results for unburned carbon in ash and for outlet temperature were validated respectively by the operating data and by the design parameter. A qualitative comparison between the results for temperature and ignition behavior in the vicinity of the burners was made, using the images of a high temperature resistant video camera system.

At the same line Choi and Kim (2009), also using the code FLUENT, investigated numerically the characteristic of flow, combustion and NOx emissions in a 500 MW tangentially fired pulverized-coal boiler. They showed that the

## Methodology

### Boiler Description

The boiler system under study is a 700 MW boiler with a tangential-firing configuration. The firing equipment consists of 28 coal burners. The burner system provides pulverized coal to the boiler from pulverizers where it has been crushed to consistent sizes. The primary airflow carries the fine coal to

the burners for combustion to take place in the boiler furnace. The furnace is rectangular in shape with four burners firing from each corner, thus creating a fireball at the center of the furnace.

The numerical modelling of the boiler combustion process was carried out using an ANSYS-FLUENT relation among temperature, O<sub>2</sub> mass fraction and CO<sub>2</sub> mass fraction has been clearly demonstrated based on the calculated distributions, and the predicted results have shown that the NOx formation in the boiler highly depends on the combustion process as well as the temperature and species concentration. The strategic role of energy and the current concern with greenhouse effects enhance the importance of the studies of complex physical and chemical processes occurring inside boilers of thermal power plants. Combustion comprises phenomena such as turbulence, radiative and convective heat transfer, particle transport and chemical reactions. The study of these coupled phenomena is a challenging issue. The state of the art in computational fluid dynamics and the availability of commercial codes encourage numeric studies of the combustion processes. In the present work, a commercial CFD code, CFX © Ansys Europe Ltd., was used to study the pulverized-coal combustion process in a 160 MW thermal power plant erected in the core of the Brazilian coal reserves region, with the objective of simulating the operation conditions and identifying inefficiency factors. 2021 R1 CFD package assuming steady, turbulent and compressible flow. The research commenced with the collection of a boiler design data and configuration. CFD models were built based on the design and validated using operational data from the boiler. The model was then used to predict the behavior of several coal combustion characteristics such as flame temperature, O<sub>2</sub> & CO species composition and furnace exit gas temperature (FEGT) with the same boiler setting which were mass flow of air & coal and burner tilting angle.

The properties of coals

Coal properties	Coal A	Coal B	Coal C
Calorific Value, kJ/kg	5732.57	6122.24	6495.45
Moisture, %	13.30	5.89	6.55
Volatile matter, %	43.80	41.03	40.98
Fixed carbon, %	41.25	43.69	45.32
Ash, %	1.65	9.40	7.16
C, %	61.80	70.80	73.45
H, %	5.63	5.76	5.76
O, %	31.21	21.90	18.81
N, %	1.09	1.34	1.46
S, %	0.27	0.50	0.53

## GEOMETRY

For importing the Model of Heat Exchanger,

Start workbench 2021 R1 → select the fluid flow (fluent)

→ Edit Geometry → import External Geometry → Choose the image file which is in IGES format

→ Generate as shown in the Fig 5.2

### Geometry:

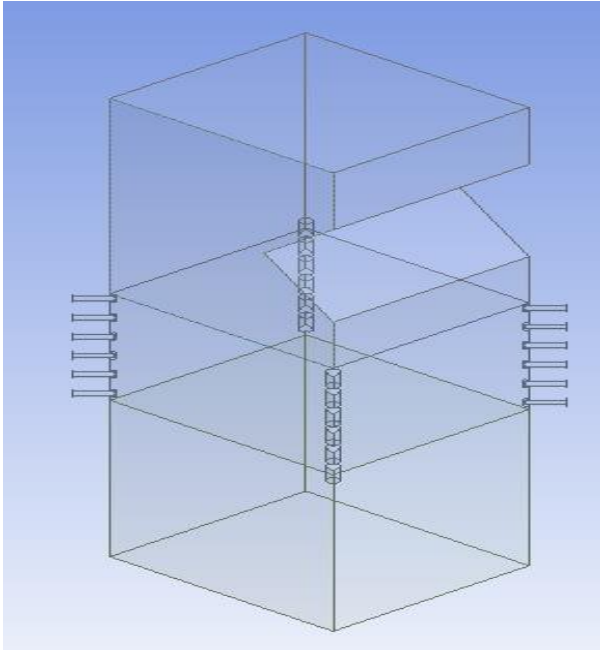
Geometry was created in 3D modelling software Creo and was imported in to Ansys environment

Geometry specifications

length

28.6 m

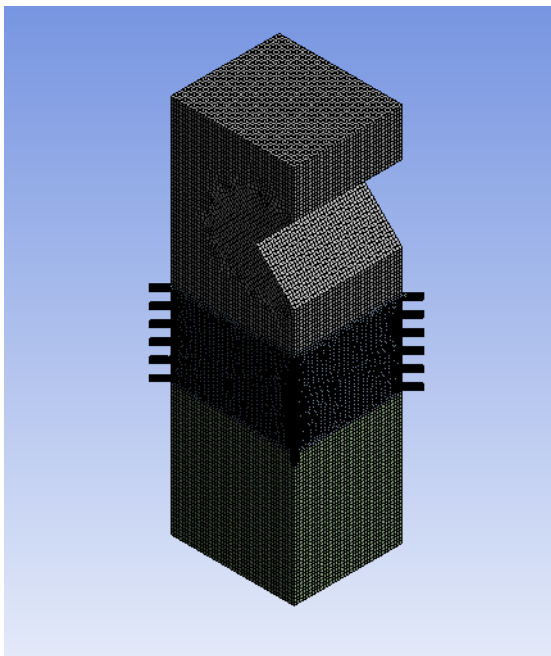
Breadth	24.9 m
Height	64.5 m
Burner Diameter	900mm
Number of burners	24



Geometry

### Mesh Generation

The geometry and mesh generated for the boiler model is shown in Figure 3.1. The overall framework of the meshing scheme used in this study is quadrilateral mesh. Fine mesh was constructed in critical regions, such as in the area closed to burners, primary and secondary nozzles and within the wine box. The model was developed based on the actual operating boiler in the power plant. From the drawing obtained, few modifications were made to avoid extreme skewness level that might affect the stability of the calculation. These modifications, however, do not affect the final outcome as the main aim is to observe the flow



Meshing of 3D model of furnace

### CFD MODELLING

#### Coal combustion:

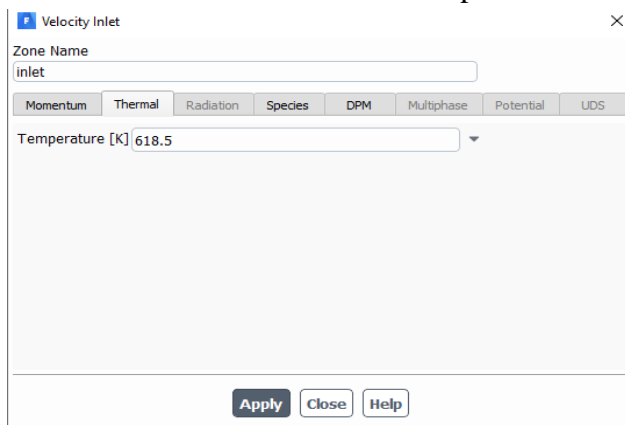
A commercial CFD program, ANSYS Fluent version 2021 R1, was used to simulate the oxy-coal

and combustion temperature of the overall furnace flow domain. The number of mesh constructed is approximately 2.3 million cells. Prior grid dependency study has been undertaken and it is shown that the current mesh is sufficient enough to resolve the flow field, especially in complex regions where flow properties are critical. Comparison of the simulation results with different mesh density is shown in Figure 2. The mesh quantity was reduced by 20% and increased by 20%. It is shown that the differences of the predicted temperature between these varying meshes were negligible.

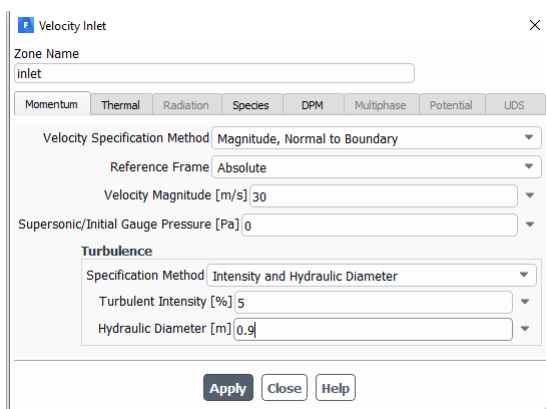
combustion process in the reaction zone of the EFR. The computations were performed in a three-dimensional structured grid consisting of ~75,000 cells, whose details

have been reported previously. The CFD code

solved the appropriate transport equations for the continuous phase, and a Lagrangian approach was used to calculate particle trajectories through the calculated gas field. The Realizable  $k-\epsilon$  turbulence model was employed to model the dynamic of the flow. Heat transfer by radiation was accounted for by the Discrete Ordinate Model because of the higher accuracy and smaller optical length of the EFR, together with the cell based Weighted-Sum-of-Gray-Gases Model (WSGGM) for the radiative properties of the gases. Other researchers have developed specific models for gas radiative properties in oxy-fuel environments implemented a new gaseous radiative properties model in CFD simulations in a laboratory-scale 0.8 MW furnace and found little difference in the radiation source in comparison with



Inlet Boundary Conditions



After initializing the CFD model, run the calculation. Set the number of iterations 2000 and run the solution until the problem is converged.

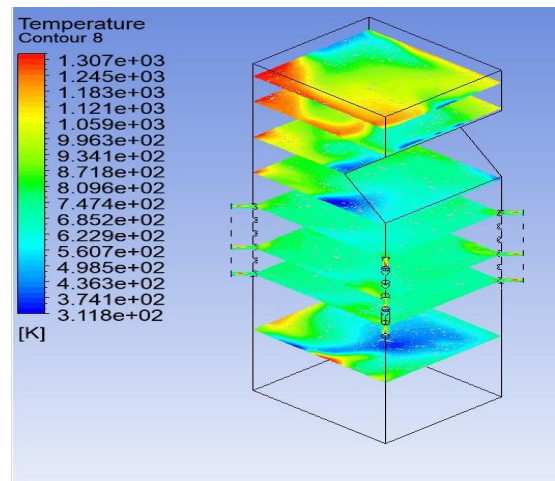
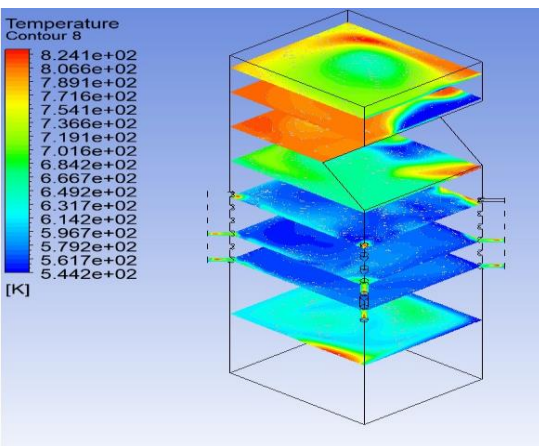
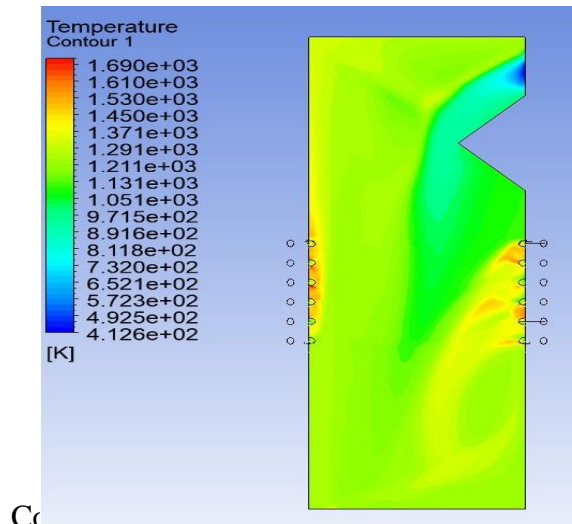
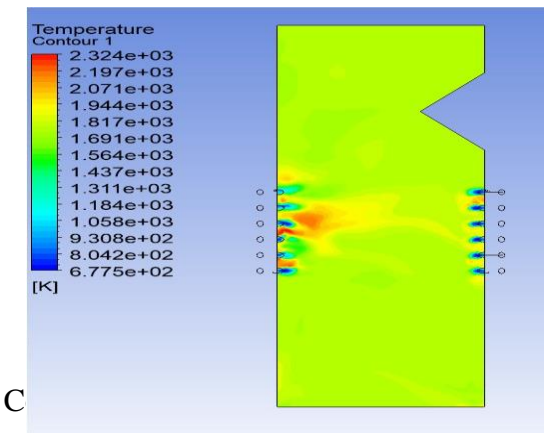
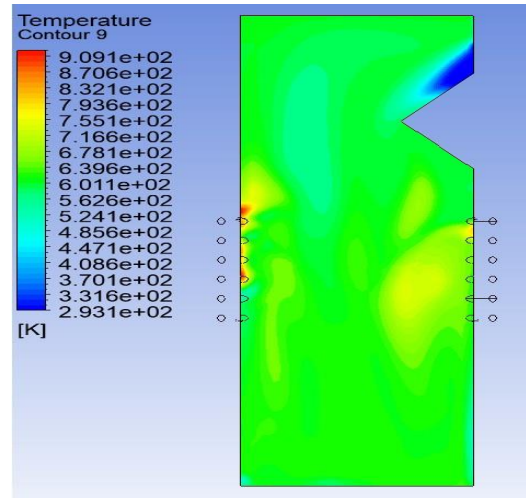
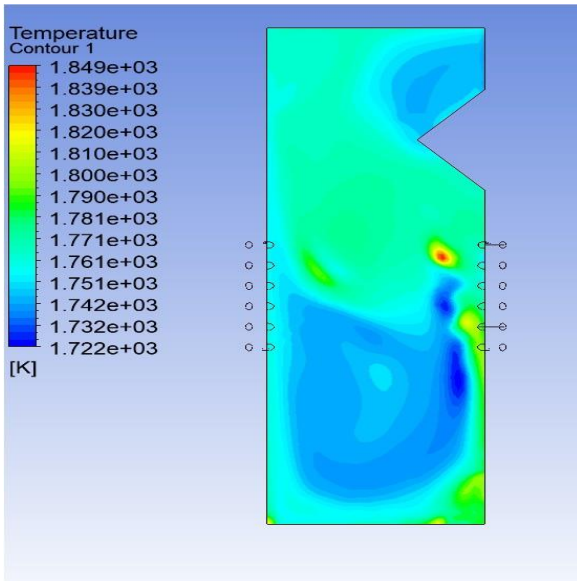
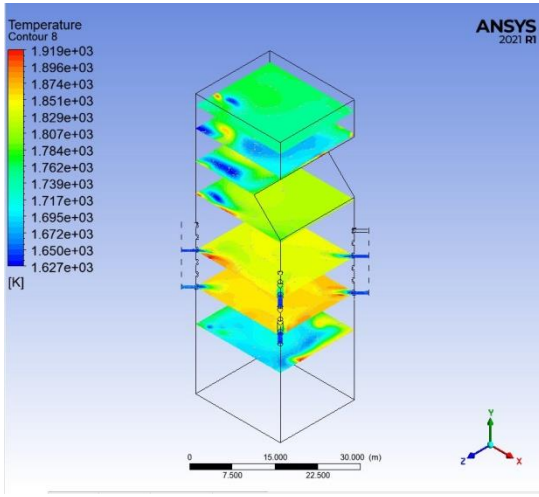
## RESULTS AND DISCUSSION

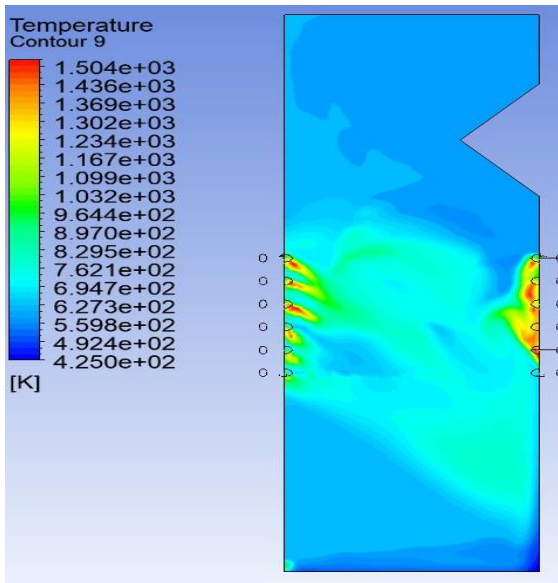
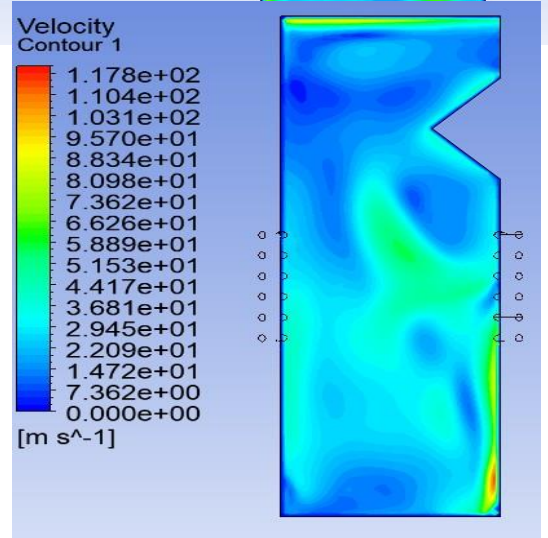
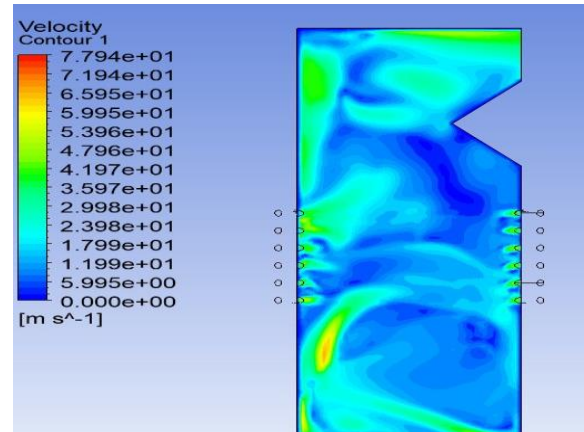
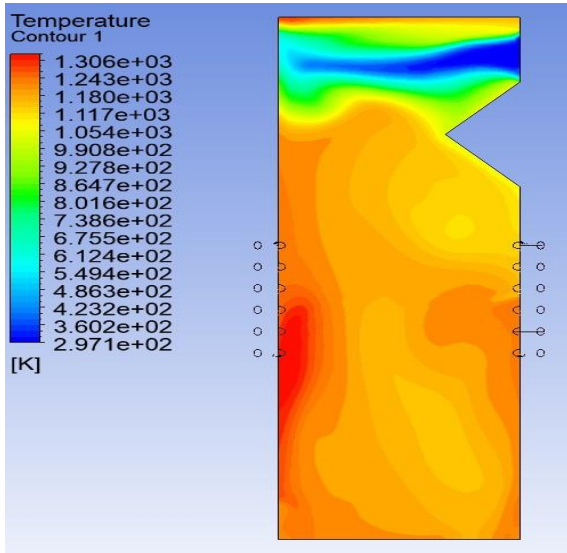
Temperature Distribution: Coal:

the WSGGM model. They concluded that the two models made negligible difference in the simulation results when applied to small-scale oxy-fuel combustion modelling, but their implantation is necessary in modelling large-scale oxy-fuel furnaces.

### Boundary Conditions:

The boundary conditions were obtained from the daily operational data at 100% Boiler Maximum Continuous Rate (BMCR). The inlet conditions are the air and coal flows entering the domain from the burner nozzles. Coal flow rate and combustion stoichiometric ratio were set as 30 m/s and 1.2 respectively. Temperatures of combustion air are set as 345 °C. Pulverized coal size was modelled by a Rosin-Rammler distribution between 300  $\mu\text{m}$ . The outlet condition is the flue gas passage at boiler rear pass.

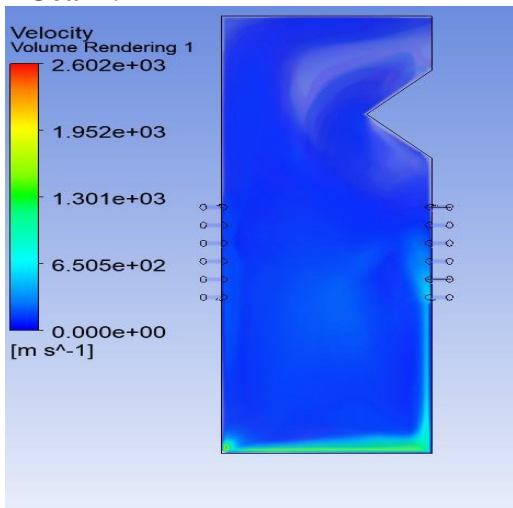




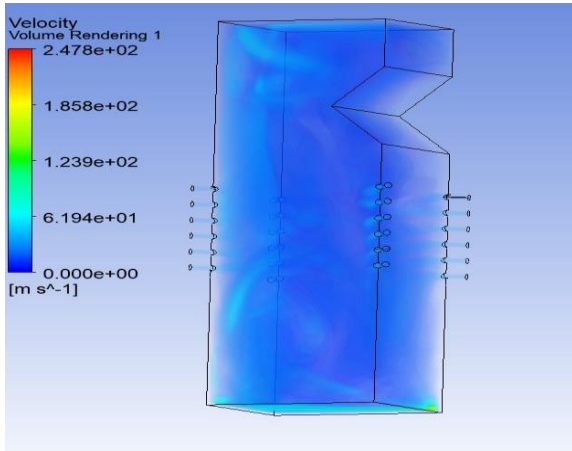
**Velocity Contours:**

CoalC:

**CoalB:**

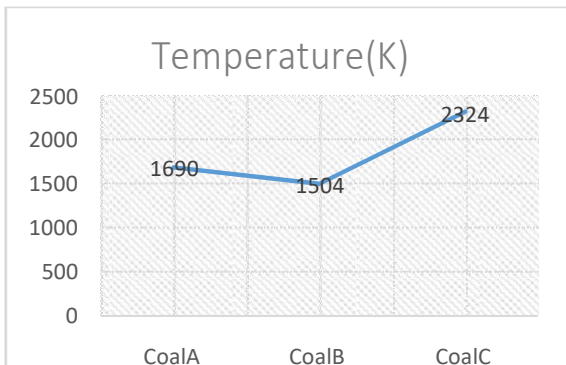


CoalA

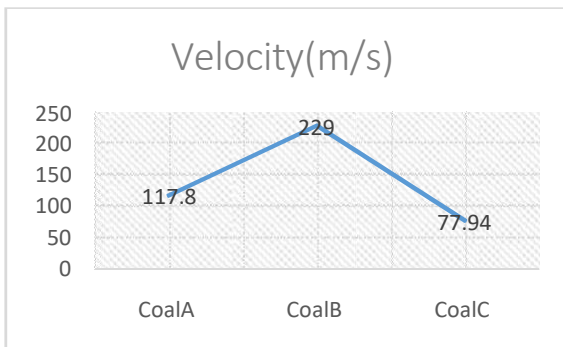


	Temperature (K)	Velocity (m/s)
Coal A	1690	117.8
Coal B	1504	229
Coal C	2324	77.94

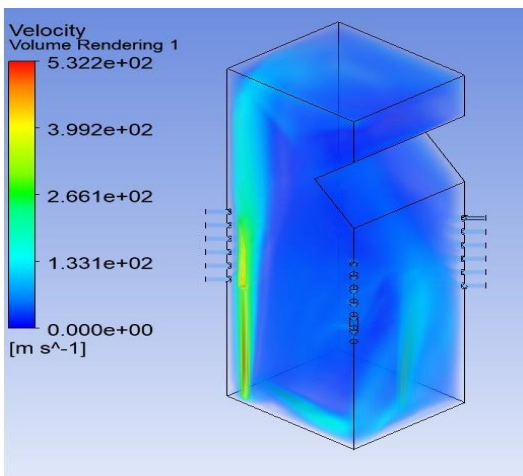
Table



CoalsamplesTemperature



CoalsamplesVelocity



Fromtheabovecontourplots,

**Conclusion:**

To get a better grasp on how various sub-bituminous coals burn inside the boiler,

computational fluid dynamics (CFD) simulations of flow and combustion in a full-scale power station furnace have been conducted. Predicted findings reveal a relationship between the coal types and the distributions of temperature, velocity, O<sub>2</sub>, and CO species; three appropriate coals were used for boiler burning. A high furnace temperature is the result of burning coal with a high calorific value, which releases more energy during combustion. Another important factor that may affect the temperature distribution is the fuel ratio. The compositions of the flue gases are affected by the combustion behaviour in the boiler, which in turn affects the distributions of CO and O<sub>2</sub>. Validation of the model was done using data from the boiler's performance, including boiler exit gas temperature, O<sub>2</sub>, and CO %, and the results show that the temperature and velocity profile match the expected behaviour of a tangential-fired boiler.

This effort should keep simulating with a larger variety of sub-bituminous coal qualities in order to better understand the complicated physical and chemical reactions within boilers. Further research into how different operational conditions impact combustion outcomes is required. The boiler's performance may be optimised by adjusting its specifications to accommodate a broad variety of coal qualities.

- Coal Sample C reaches a maximum temperature of 2324 K, whereas samples A and B reach temperatures of 1690 and 1504 K, respectively. The reason for this is the higher amount of coal (fuel) in samples A to C. Coal A has a lower coal concentration relative to the oxygen in the mixture. Use of coal sample A results in oxygen waste.
- The proportions of coal and oxygen in the combination are enough for coal B. As a result, using coal sample B does not result in any oxygen or coal waste.
- The coal concentration is higher than the oxygen provided in the mixture when dealing with coal C. Wasted coal is the result of using coal sample A. The result will be additional pollution due to incomplete combustion.

From an operational standpoint, it is possible for scales to form in the tubes as the boiler temperature rises, which will decrease the boiler's efficiency. Coal sample B, however, produces the best results out of the three. However, we may use Coal sample A if the boiler's capacity is large.

#### Future Scope:

The temperature at the intake, the amount of coal and oxygen in the mixture, the flow rate, the pressure of the mixture, the furnace's height, and the coal's calorific value are all factors that affect the efficiency of coal combustion. Thus, according to the boiler's design circumstances, the efficiency of the furnace may be changed by adjusting the aforementioned factors. As a result, there is always room for improvement in terms of combustion efficiency. This is a partial

list of some of them:

1. Increasing the availability of oxygen for full combustion may improve combustion efficiency. Which can be done in two ways.
  - Adding more oxygen to the oxy-coal mixture.
  - Making sure the burner has enough oxygen by using a secondary channel.
2. To enhance efficiency, you may change the speed of the incoming oxy-coal mixture.
3. Enhancing efficiency may be achieved by modifying the inflow oxy-coal mixture's temperature conditions.

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